Near well simulation of CO_2 injection for Enhanced Oil Recovery (EOR)

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Abstract

Relative low recovery rates are a major challenge in oil industry. Estimates show that more than half of the oil remains in the reservoir after shut down. Therefore there are strong incentives for using CO_2 injection for Enhanced Oil Recovery (EOR). CO_2 injection also contributes to the control of the greenhouse effect.

Generally CO_2 is injected as a supercritical fluid. At sufficiently high pressures and temperatures, it achieves miscibility with oil.

In this research simulations are performed using OLGA-Rocx. The effect of CO_2 injection is represented through the change of oil relative permeability and the pressure effect of the injection well. Higher oil production is obtained when the residual oil saturation is reduced. The simulations indicate that, CO_2 should be injected as early as possible to increase the oil production. A rapid oil production rate can be achieved if the injection well is located on the top of the reservoir. Also the oil production is proportional to the injection pressure.

Keywords:CO_2-EOR, Near well simulation, Relative permeability curves, OLGA, ROCX

1 Introduction

Energy is a crucial requirement of our everyday lives and mainly this energy comes from crude oil. Oil is generally referred as a non-renewable resource. According to International Energy Statistics, in year 2013 the total global oil supply was approximately 91,000 thousand barrels per day (Administration 2014). Reservoir estimations conducted in 2013 suggest that US is able to produce oil for another 12 years using conventional recovery techniques. Similarly Canada has reserves for 4 years excluding oil sands; Saudi Arabia and Kuwait have reserves for another 77 and 105 years respectively (Conglin Xu 2013). Thus it is very essential to improve technologies to recover more oil from existing production fields.

Primary production is the first phase of the productive life of an oil field and in that phase oil is produced without any injection to the reservoir formation. The natural pressure in the reservoir is sufficient for the oil in the formation to flow into the production wellbore. Oil can be recovered up to 20% of the oil originally in the rock (OOIP) in this phase and this depends on the characteristics of the rock formation and properties of the oil. Once the wells start to produce oil, the pressure in the formation is reduced causing a continuous decrease in the oil production rate. Water flooding is done for maintaining the reservoir pressure in the secondary phase to produce more oil. This phase has a potential of recovering further 15% - 20% of the OOIP.

Even after completion of the primary and secondary phases of the oil production, 65% or more of the OOIP is left in the reservoir formations (Institute for 21st century energy). The reasons for this poor oil recovery are that the oil is bypassed due to poor sweep efficiency, oil which is physically unconnected to the well bore and oil which is trapped by viscous, capillary and interfacial tension forces. The characteristics of the oil are changed using an injectant to recover a significant amount of oil remaining in the formation (Melzer 2012). These technologies are called Tertiary recovery or Enhanced Oil Recovery (EOR) methods and can be categorized into three types. These types are thermal methods, chemical methods and miscible gas flooding. CO_2, N_2 and Hydrocarbon gasses can be used as miscible gases.

2 Background

2.1 CO_2 Enhanced Oil Recovery (EOR)

CO_2- EOR has been used by the oil and gas industry for over 45 years (Sean I. Plasynski 2008). The two major countries having several projects regarding CO_2 EOR are United States and Canada. CO_2 is considered as an excellent solvent for miscible floods and CO_2 injection is a promising EOR mechanism. CO_2 is injected into the depleted oil fields through one or more injection wells which are located around the production well as the oil production is going down. This has the ability of recovering an additional 15% to 20% of OOIP (Institute for 21st century energy). In addition to production of energy by recovering more oil by applying CO_2 EOR, it has direct environmental benefit by sequestering CO_2 permanently in the old oil formation. According to estimations, the U.S and Canada have the potential to sequester more than 82 billion tons of Carbon (Sean I. Plasynski 2008).

2.2 Properties of CO_2

Pure CO_2 is a non-combustible gas having no colour or odour. The molecular weight of CO_2 is 44.010 g/mol and in given pressure and temperature CO_2 is denser than air. Figure 1 shows the influence of pressure and temperature on the density of CO_2.

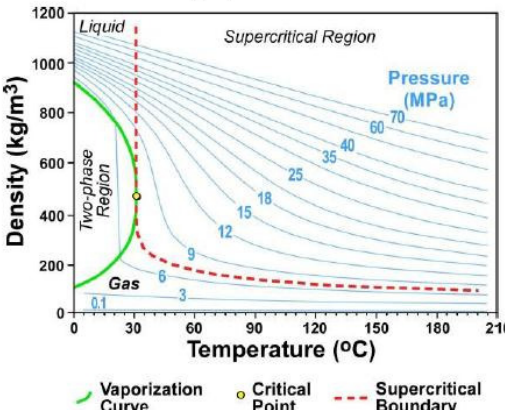

Figure 1. Relation of the density of carbon dioxide to temperature and pressure (Steve Whittaker 2013)

Below the critical temperature, CO_2 can exist either as a gas or liquid. After exceeding the critical temperature CO_2 exists as a gas. However when pressure is exceeding the critical pressure, the CO_2 becomes a supercritical fluid. Critical properties of CO_2 are given in Table 1.

Table 1. Critical properties of CO2 (Mathiassen 2003)

Parameter	*Value*
T_C	31.05 ^{0}C
P_C	73.9 bar
V_C	94 cm^3/ mol

CO_2 at its supercritical pressure and temperature is completely miscible with oil. Because of that, oil moves through the rock pore spaces more easily yielding more oil production. (Institute for 21st century energy). As the reservoir fluids are produced through the production wells, the reservoir pressure will decline. Then the injected CO_2 has the ability to reconvert into gaseous state and provides a gas lift which is similar to original reservoir natural gas pressure (Alomair and Iqbal 2014).

The main advantage of CO_2 compared to other gasses is its ability to extract heavy hydrocarbon components up to the range C30. Some of the main characteristics of CO_2 which are effective in extracting oil from porous rock are mentioned below (Holm and Josendal 1974).

- CO_2 promotes swelling

Oil swelling occurs due to solubility of CO_2 in oil. Pressure, temperature and the oil composition are the main key parameters which effect on the degree of swelling. Swelling is important because the residual oil saturation is inversely proportional to the swelling factor.

- CO_2 reduces oil viscosity

The dissolving of CO_2 in oil reduces the oil viscosity as well. But the overall viscosity reduction depends on the initial oil viscosity. The reduction of oil viscosity will be larger if the initial oil viscosity is high.

- Interfacial tension reduction

CO_2 has the ability to reduce the interfacial tension by dissolving in oil. This has significant influence on the relative permeability curves and increases the oil relative permeability.

- CO_2 exerts an acidic effect on rock

CO_2 dissolves in water and forms carbonic water in the front section of CO_2 injection. This leads to dissolution of calcite in the rock formation as following reaction.

$H_2O + CO_2 + CaCO_3 \rightarrow Ca(HCO_3)_2$

These rates of reactions in carbonated rocks are faster than in sand-stones. Because of this, the porosity and the permeability of the formation can be changed due to CO_2 injection.

- CO_2 reduces the effect of gravity segregation

CO_2 has the ability to reduce density difference between oil and water by dissolving in oil and water. This leads to reduced chance of gravity segregation.

2.3 Mechanisms

The main mechanisms of CO_2- EOR depend on the conditions of injecting CO_2, the reservoir conditions (pressure and temperature) and the oil composition. Generally CO_2 is not miscible with reservoir oil at the first contact. At sufficiently high pressures and temperatures, CO_2 achieves dynamic miscibility with oil through multiple contacts. The minimum pressure at which CO_2 and oil are completely mixed with each other at any proportion is called the minimum miscibility pressure (MMP). Injection of CO_2 at a pressure equal to or above the MMP is called miscible CO_2 EOR and CO_2 flooding at a pressure below the MMP is called immiscible CO_2 EOR.

2.3.1 Miscible CO_2 EOR

CO_2 EOR can be achieved when CO_2 is flooded into a reservoir having low viscous oil, at a pressure equal to or higher than MMP. Mixing reservoir oil with CO_2 does not happen instantaneously. When the reservoir oil is in contact with the injected CO_2, the oil begins to dissolve into the dense CO_2 and the dense CO_2 begins to dissolve into the oil. Eventually the oil and the injected CO_2 become one single phase due to repeated contacts with time. The instance where CO_2 is completely mixed with oil, is termed as miscible CO_2 EOR. Under this process vaporization of crude oil, development of miscibility, and reduction of interfacial

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tension occurs within the reservoir. This leads to more oil production due to more efficient sweep of oil (Steve Whittaker 2013).

When miscible CO_2 EOR is performing, several compositional zones are developed in the displacement direction within the reservoir as shown in Figure 2. As the first point of contacting CO_2 with reservoir oil, a miscible front will be generated. In this front lighter hydrocarbon molecules will be transferred gradually from the oil to CO_2. Then this front will dissolve in oil and act as a single phase under favourable pressure and temperature conditions. This makes it easier for the oil to move towards the production wells.

Figure 2. Illustration of the zones that develop in miscible CO2 flooding (Steve Whittaker 2013)

Most of the oil recovery operations are designed to maintain the reservoir pressure above the MMP in order to operate under fully miscible conditions. These pressure conditions can be achieved naturally in the reservoirs below about 800m of depth.

2.3.2 Immiscible CO_2-EOR

When the reservoir pressure is not sufficient to exceed the MMP or the reservoir contains oil having high density and viscosity (heavy oil) immiscible CO_2-EOR is carried out. Even though the miscibility between oil and CO_2 is not significant; CO_2 will dissolve in the oil phase. Hence reduction of crude oil viscosity and swelling occur and these are the most important effects under the immiscible CO_2 EOR process (Alomair and Iqbal 2014). In addition to that the reservoir oil is pushed effectively towards the production well by the injected CO_2. Therefore due to these mechanisms, an additional portion of the remaining oil in the reservoir can be recovered. In generally, immiscible CO_2 -EOR is much less efficient compared to miscible CO_2-EOR in recovering the residual oil.

2.4 Benefits of CO_2-EOR

The main advantage of CO_2 EOR is the economic benefits due to additional oil production by extending the productive life of the exiting oil fields. In addition to the economic benefits, environmental benefits are also achieved. These benefits include permanent sequestering of captured CO_2 in the old oil formation without releasing it into the atmosphere. Hence the effect due to greenhouse gas on the global warming can be reduced. Old production wells can be converted into CO_2 injection wells. Hence there is no need to drill new wells which would lead to land degradation. Therefore energy production, energy security and environmental sustainability can be enhanced via CO_2-EOR.

2.5 Limitations of CO_2 EOR

Supplying CO_2 to the place where the oil fields are located is one of the major challenges for CO_2 EOR. Availability of low cost CO_2 is the main challenge. This includes all cost for purchasing and transportation. To obtain a great performance the purity of CO_2 should be higher than 95%. Thus, purifying cost should also be considered. From the amount of CO_2 currently used for EOR, about 75% is extracted from naturally occurring deposits located near the oil fields in order to ensure economic feasibility. The rest is the captured CO_2 from industrial processes such as power plants fertilizer, manufacturing plants, etc. (Sean I. Plasynski 2008)

The problems associated with CO_2 EOR are gravity tonguing and viscous fingering. These are due to high mobility, lower density and viscosity of CO_2 compared to the oil in the reservoir. In order to avoid these problems to some extent and improve the sweep efficiency, the following methods are carried out:

- WAG (Water Alternating Gas) process

In order to improve sweep efficiency water and CO_2 are injected to the formation as alternating slugs.

- Injection of foaming solutions together with CO_2

By adding foaming solutions in more permeable areas of the reservoir, the mobility of CO_2 can be reduced. Hence sweep efficiency can be improved. (Mathiassen 2003)

- Installation of well packers and inflow control devices

CO_2 EOR is not suitable for all oil fields and the effectiveness of CO_2 EOR depends on several factors such as oil composition, depth, temperature and other characteristics of the reservoir (Steve Whittaker 2013). The characteristics of the reservoir such as reservoir heterogeneities, porosity, permeability and wettability must be considered when designing a CO_2 EOR system.

3 Development of the model in OLGA-Rocx

The impact of CO_2 injection as an enhanced oil recovery mechanism is analysed via near-well simulations. In this chapter, the development procedure of the simulation models is described.

3.1 Simulation tools

The model of the near-well reservoir was developed in Rocx and coupled with the wellbore model in OLGA. The simulation results are presented through TECPLOT and OLGA.

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The objective of this study is to conduct computational simulations to study the effect of CO_2 injection as an EOR technique. The study is focused on the fluid movement within the reservoir and the effect of different parameters on the amount of oil produced. A relatively small well section is sufficient to conduct the study and more importantly, by using a smaller well section the required computational time is reduced.

In this work an oil reservoir with a thickness of 20m was considered. It was assumed that there is an enormous aquifer below the oil layer. The length of the well was taken as 25m.

3.2 Development of the near-well reservoir model

Initially a base case without any CO_2 injection was developed and simulated in order to compare the results of the more complex simulations using different CO_2 injection parameters.

3.2.1 Dimensions of the reservoir

The considered reservoir contains a horizontal production well (a pipe) along the x-direction having a length of 25m. The production well is located in the middle of the y-axis and at 6m below the top of the reservoir. In Figure 3 a sketch of the reservoir is presented.

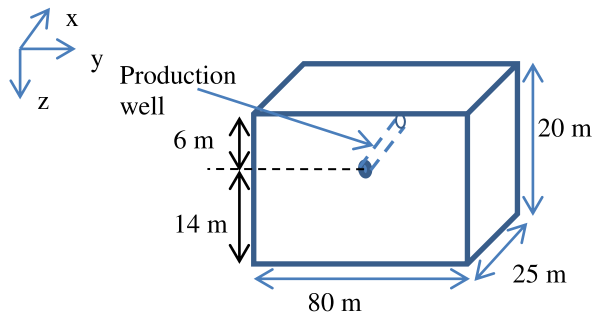

Figure 3. Dimensions of the reservoir

It is assumed that an enormous aquifer is located below the considered reservoir (at the bottom plane of the reservoir). Therefore pressure due to the water drive at the bottom of the reservoir is considered to be constant 158 bar. For the oil production, the pressure difference between the base pipe and the water drive pressure is approximately 10 bar. Hence, the base pipe pressure corresponds to 148 bar.

3.2.2 Grid

The geometry illustrated in Figure 3 was defined in Rocx through the rectangular coordinate system. The grid of the reservoir was divided into 1, 39 and 20 elements in *x, y* and *z* directions respectively.

The elements in *x* and *z* directions were considered to have constant length. In order to study the close surrounding of the well bore in greater details, the grid spacing in the y direction was defined to make a finer grid in the centre. The view of the grid in the (*y,z*) plane is presented in Figure 4.

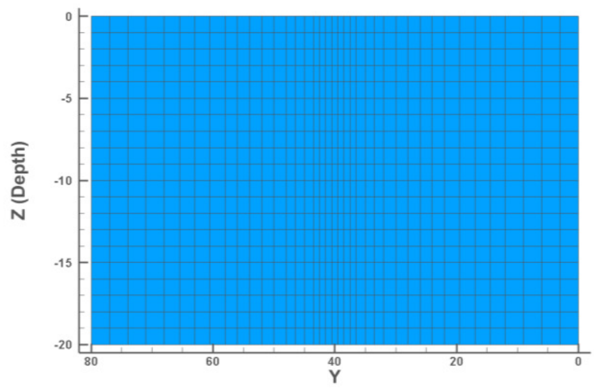

Figure 4. Mesh of the *yz* plane

3.2.3 Fluid properties

The properties of the oil, associated gas and water were specified and the black oil model was used for the simulations. The defined fluid properties and the reservoir conditions are summarised in Table 2.

Table 2. Fluid properties and the reservoir conditions

Label	*Value (unit)*
GOR	50 Sm^3/ Sm^3
Gas specific gravity	0.64
Oil specific gravity	0.85
Measured oil viscosity	10 cp
Measured at temperature	48.9 ^{0}C
Measured at pressure	158 bar

For these simulations a homogeneous reservoir was considered with porosity of 0.15% (Gu and Deo 2009). Permeabilities in the *x,y* and *z* directions of each cell were defined as 400 mD, 400 mD and 40 mD respectively.

3.2.4 Relative permeability curves

Two sets of relative permeabilities are required for three phase flow calculations in the reservoir. Those are,

- The water relative permeability (k_{rw}) and oil-water relative permeability (k_{row})
- The gas relative permeability (k_{rg}) and liquid-gas relative permeability (k_{rog})

Relative permeability values were defined as a function of water or gas saturation. The respective relative permeability curves are shown in Figure 5 (Gu and Deo 2009). Since the location of the crossover point and endpoint of the relative permeability values are functions of wettability of the rock formation (Kasiri and Bashiri 2011), this reservoir formation can be considered as a water-wetted reservoir.

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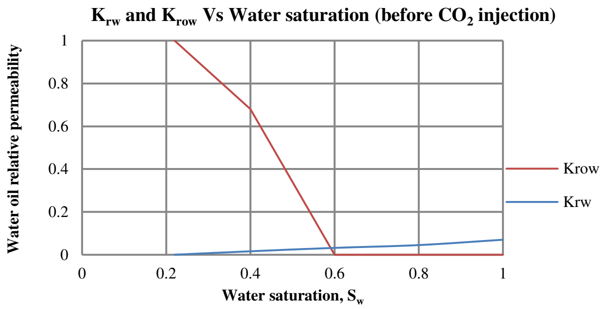

Figure 5. The water relative permeability (k_{rw}) and oil-water relative permeability (k_{row}) (Gu and Deo 2009)

For all the simulations the relative permeability curves shown in Figure 6 were used for the gas phase.

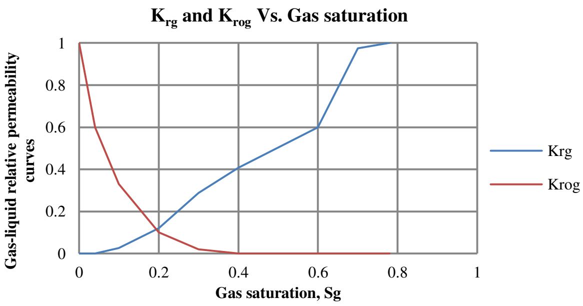

Figure 6. The gas relative permeability (k_{rg}) and liquid-gas relative permeability (k_{rog}) (Gu and Deo 2009)

3.2.5 Initial and boundary conditions

The initial pressure and the temperature of the reservoir were set as 158 bar and 48.9^{0}C respectively. It is assumed that the reservoir is completely filled with oil initially.

According to the defined reservoir, the production well is parallel to the *x*-axis. The (*y,z*) coordinates of the well are (20,6) in the (*y,z*) plane. The diameter of the well is 0.1m. The pressure and the temperature of the well are 158 bar and 48.9^{0}C respectively.

Pressure at the bottom boundary of the reservoir is considered to be constant and equal to 158 bar due to large aquifer below the oil reservoir. Therefore in Rocx this boundary condition is defined as a reservoir having a water-feed at the bottom plane (Z=20). The temperature of the boundary is the same as in the reservoir and equals to 48.9 ^{0}C.

3.3 Development of the CO_2 injection cases in Rocx

These cases were developed to study the effect of different CO_2 injection parameters on oil production. The effect of CO_2 injection was represented via the changes in the relative permeability curves and the pressure source through the injection well.

3.3.1 Change of relative permeability curves

As OLGA-Rocx does not support injection of CO_2 directly, a different approach had to be followed by changing the relative permeability curves.

For these simulations it was assumed that the residual oil saturation will be reduced from 0.4 to 0.1 compared to the reference case. The modified relative permeability diagram is shown in Figure 7.

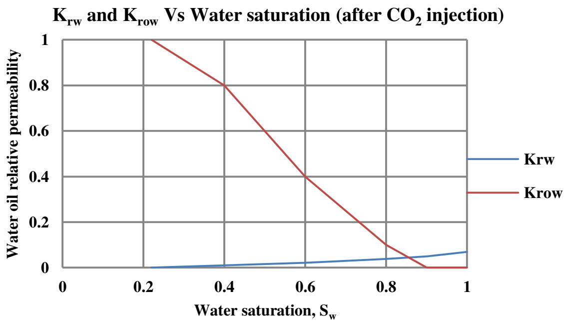

Figure 7. Water -oil relative permeability curves after CO2 injection

3.3.2 Effect of CO2 injection as a pressure source

By injecting a gas feed, the pressure effect on the CO_2 injection can be simulated. As the CO_2 gas feed cannot be directly defined in Rocx, a gas feed was defined with the properties of super critical CO_2 at 158 bar and 48^{0}C.

Under these simulations, the location of the CO_2 injection was defined in the (*y,z*) plane by changing the (*y,z*) coordinated. These were defined as pressure (reservoir) boundary conditions.

3.4 Development of the well and wellbore model in OLGA

The version of OLGA 7.3.1 was used as the main program to run the simulations and the model of the well and well bore were developed as shown in Figure 8.

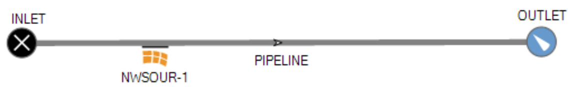

Figure 8. Layout of the model developed in OLGA

Then the pipe line was configured to have a length of 25 m in the x direction. The settings of the components were defined through the Model Browser. The reservoir model developed in Rocx was coupled with the near-well source.

The properties of the fluids and the reservoir conditions were defined according to the model developed in Rocx.

4 Simulation results

The results of the OLGA-Rocx simulations are illustrated and analysed in this section to study the effect of CO_2 injection as an EOR mechanism.

4.1 Effect of residual saturation

The effect of CO_2 injected is simulated via changing the relative permeability curves. Both the curvature and the residual oil saturation of the relative permeability curves can be changed due to CO_2 injection. In this section, the effect of the change of the residual oil saturation is considered.

In practice, it is economical to produce as much oil as possible using water drive. Therefore CO_2 was injected after the water breakthrough has occurred.

The accumulated volumes of oil and water produced with CO_2 injection is compared with the reference case which has no CO_2 injection. The comparison of the results is presented in Figure 9. One can clearly see that by decreasing the residual oil saturation, oil production has been enhanced significantly while the water production has been reduced. The change of oil and water production curves can be explained by the new relative permeability curves presented in Figure 7. Oil has a higher permeability compared to the water up to the water saturation of 0.8 and oil will be produced up to a water saturation of 0.9. In the reference case, oil production was terminated when the water saturation reaches 0.6. Therefore the decrease of residual oil saturation has increased the oil production while reducing the water production.

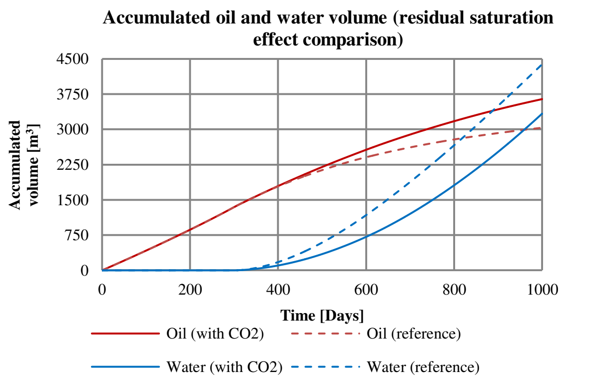

Figure 9. Residual oil saturation effect - accumulated fluid volume comparison

For economical purposes, it is important to analyze the oil production as a function of the water cut of the final product. In Figure 10 the accumulated oil volume of the two cases (CO_2 injection and reference case) are presented against the in-situ water cut.

It is clearly seen that the injection of CO_2 has significantly increased the quality of the final product. That is, when reaching a particular water cut, CO_2 injection has produced a higher amount of accumulated oil compared to the reference case.

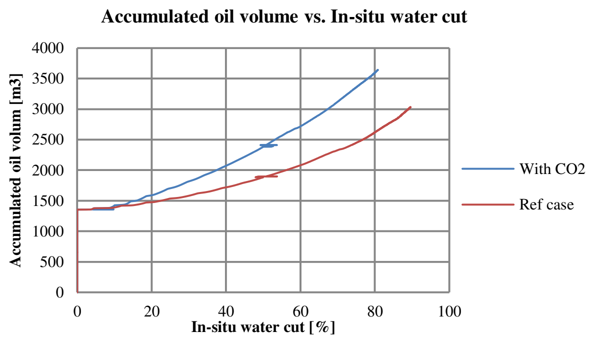

Figure 10. Accumulated oil volume vs. In-situ water cut

4.2 Effect of the curvature of the relative permeability curve

The chemical and physical properties of oil in the reservoir can change as CO_2 gets dissolved in oil. As a result the curvature of the relative permeability curves (their shapes) can be changed. A set of simulations were conducted using different types of relative permeability curves as shown in Figure 11.

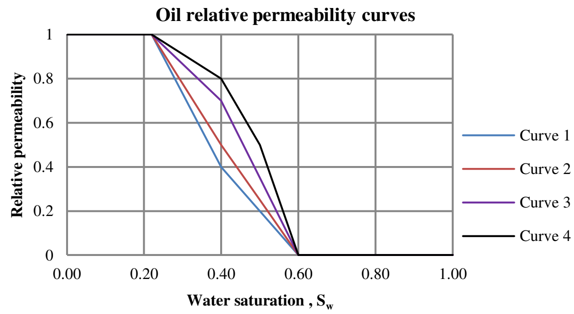

Figure 11. Oil relative permeability curves

The accumulated oil volumes related to the respective relative permeability curves are plotted in Figure 12 together with the accumulated oil volumes of the reference case and the residual saturation case which was presented in section 4.1.

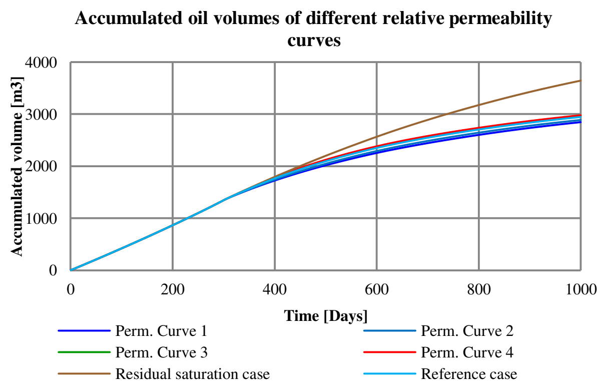

Figure 12. Accumulated oil volumes of different relative permeability curves

Based on the results illustrated in Figure 12 it can be concluded that the reduction of the residual oil

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saturation has a significant higher impact on the oil production than the changes in the curvature of the relative permeability curves. When the shape of the relative permeability curve changes from a shape of concave up towards a shape of concave down, both the accumulated oil and water volumes increase gradually. The difference between the results of the considered four curves is relatively insignificant compared to the effect of the residual oil saturation.

Since the water is also an important parameter, average water cut of the different cases are presented in Figure 13.

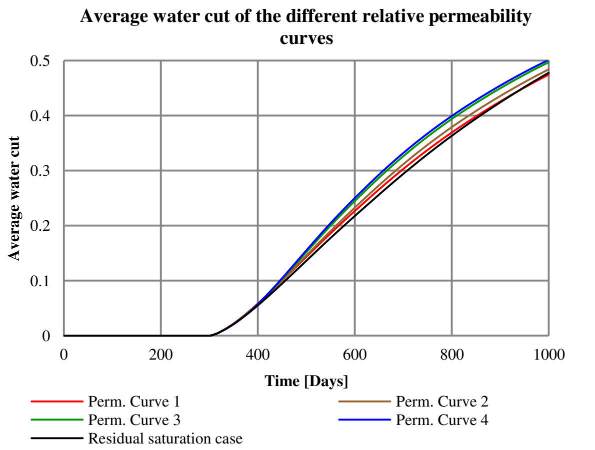

Figure 13. Average water cut of the different relative permeability curves

The average water cut of the system increases gradually when the shape of the relative permeability curve moves from a shape of concave down, decreasing towards a shape of concave up. Hence it can be concluded that even though concave down, decreasing curves produce more oil, they tend to produce at a relatively higher water cut as well. More important, it is interesting to observe that the case with lower residual saturation produces with the lowest water cut.

4.3 Effect of CO_2 injection time

The above simulation shows that additional amount of oil can be produced by injecting CO_2 to the formation (due to the reduction of residual oil saturation). It is interesting to study how the oil production will behave when the CO_2 is injected at a different time. For the study the simulation was conducted with CO_2 injection at different times and with a residual oil saturation of 0.1. Initial saturation profile for each simulation was obtained from the reference case using Tecplot. The initial oil saturation profiles are shown in Figure 14.

In Figure 15 the accumulated volume of produced oil is compared with the reference case which has no CO_2 injection. Regardless of the time of CO_2 injection, all the simulations have produced more oil than the reference case. Even though the difference between the

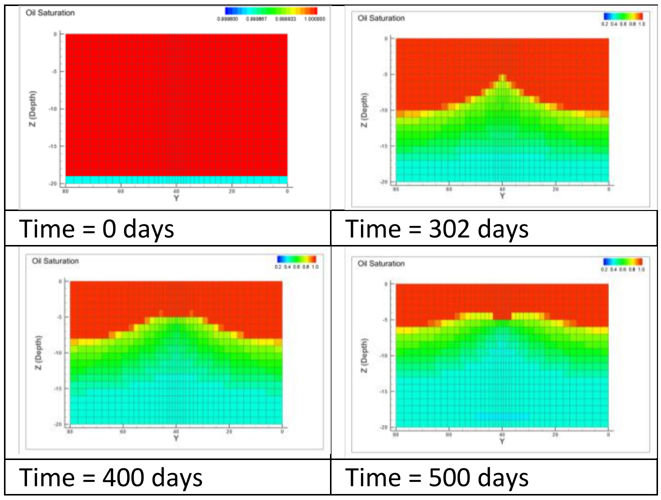

Figure 14. Initial saturation profiles for CO_2 injection time

amounts of oil produced is small for the cases with CO_2 injection, one can see that the earlier the CO_2 is being injected, the higher the oil production will be.

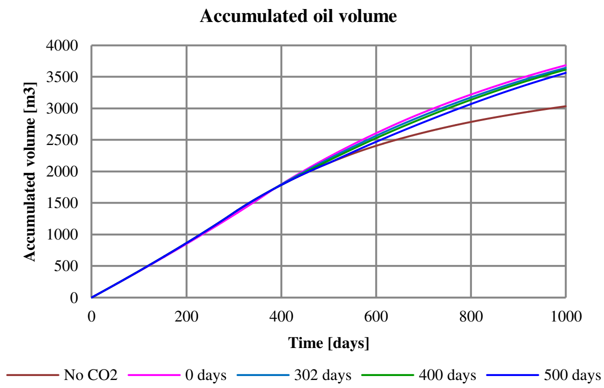

Figure 15. Accumulated oil volume (CO_2 injection time)

From the accumulated water profile presented in Figure 16 it can be observed that the amount of water produced with all the simulations having CO_2 injection is lower than the accumulated water volume of the reference case. Simulations with early CO_2 injection times tend to produce less amount of water compared to CO_2 injection simulations at later times. Another important factor is that the water breakthrough time has been delayed by 100 days by introducing CO_2 at the beginning of the simulations.

At any oil saturation value in the reservoir, injection of CO_2 makes oil more permeable. Hence CO_2 injection causes higher oil mobility leading to higher oil production. With time the oil saturation decreases due to the oil production. Therefore if CO_2 is injected early where the oil saturation is high, relatively more oil can be recovered. In addition, less water will be produced from the reservoir.

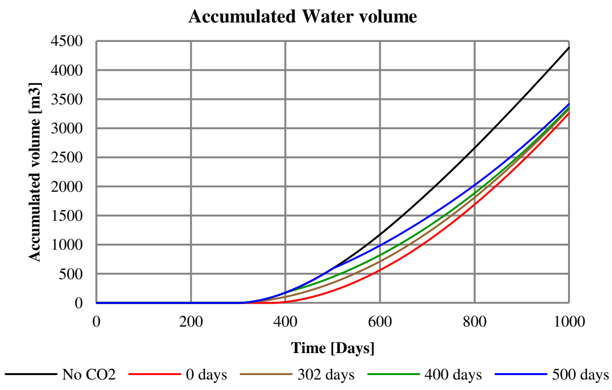

Figure 16. Accumulated water volume (CO_2 injection time)

4.4 Effect of the CO_2 injection location

For the following simulations, CO_2 was injected on the 302th day of the oil production where the water breakthrough takes place.

Figure 14 shows the oil saturation profile of the *yz* plane of the reservoir at the point of water breakthrough. In order to push the oil towards the well, CO_2 can be injected into the upper part of the reservoir to depth of maximum Z = 10. Simulations were conducted with different injection points to study the effect of the CO_2 injection location. The (y,z) coordination of the injection points (location of the injection well) of the simulations are, (1,1), (1,8), (1,9) and (1,10). In Figure 17 the accumulated oil profiles of these simulations are compared with reference case.

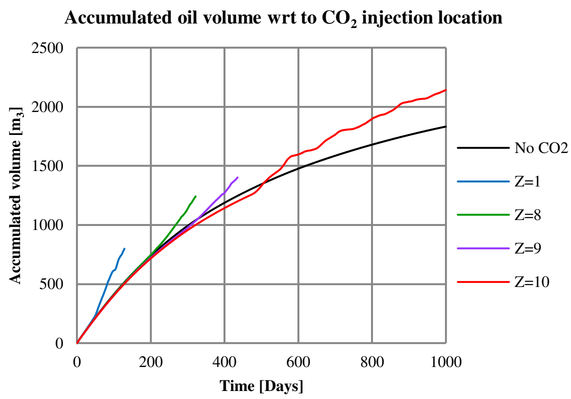

Figure 17. Accumulated oil volume wrt to CO2 injection location

The figure clearly shows that when the gas injection well is located at the top of the reservoir, higher oil production rate can be obtained. But all these simulations tend to be instable as the gas feed reaches the production well. Hence it was impossible to conduct the simulations for the whole time period. However, the trend in the curves indicates that higher oil production can be obtained if the gas injection well is located at the top of the reservoir. When a pressure source is located in the top of the reservoir, more oil should be produced and the upward water flow should be restricted. This phenomenon can be observed through the simulation results.

4.5 Effect of the CO_2 injection pressure

Another important factor in CO_2 injection is the pressure of the gas feed. For the simulations the location of the gas injection well was considered to be at the position (Z=10 and Y=1) to prevent simulation instabilities.

Figure 18 illustrates the profiles of the accumulated oil volume under different injection pressures compared with the accumulated oil volume obtained in the reference case.

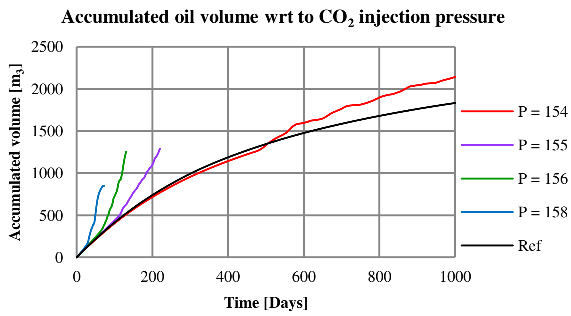

Figure 18. Accumulated oil volume wrt to CO_2 injection pressure

The figure clearly shows that as the inlet pressure increases, the rate of oil production increases rapidly. Due to the instabilities of the simulations, higher pressure simulations tend to stop. For the case with pressure of 154 bar, it can be seen that it still produces more oil compared to the reference case after 1000 days. Based on the trend of the lines, it can be assumed that as the pressure of the gas stream increases, higher amount of oil can be recovered from the reservoir. It is interesting to note that as the inlet pressure is decreased below 154 bar, the simulation crashes within a short period of time. This can be explained by considering the initial pressure distribution at the point of water breakthrough of the reservoir which is presented by Figure 19.

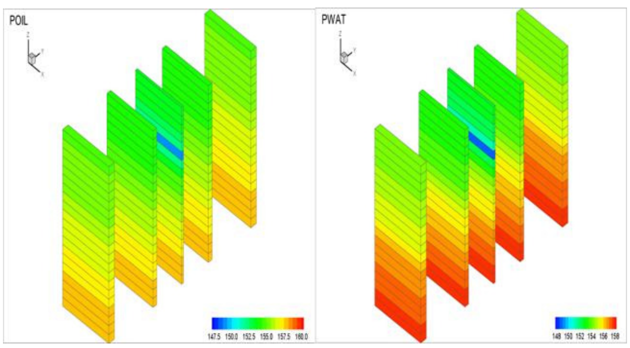

Figure 19. Pressure profile at water breakthrough

The result shows that, even though the initial pressure of the reservoir is defined as 158 bar, it is reduced down to around 154 bar in the top part of the

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reservoir, at the point of water breakthrough. Therefore CO_2 cannot be injected to the reservoir at a pressure below 154 bar. The pressure in the reservoir reduces further with time and as a result of that more oil will be produced with time compared to the reference case due to the pressure effect of the injection well. The blue coloured cell indicates the production well, where the pressure is lowest.

Simulation data for 250 days are presented in Figure 20 for the analysis of water production. According to this figure, it can be concluded that as the inlet pressure increases, accumulated water flow will be reduced.

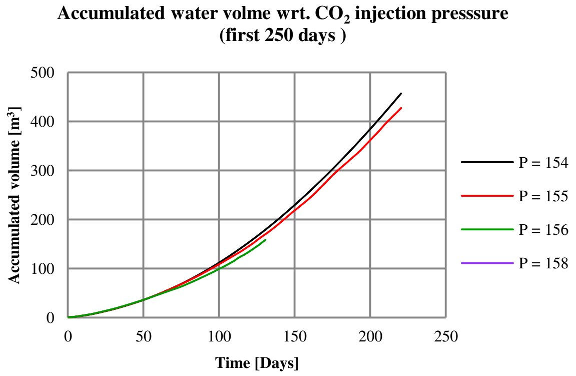

Figure 20. Accumulated water volume wrt CO_2 injection pressure (first 250 days)

4.6 CO_2 storage within the reservoir

CO_2-EOR is not only an oil recovery mechanism but also a possible partial solution for global warming. The ability to store CO_2 within the reservoir is an additional advantage of CO_2-EOR. The gas saturation profile after CO_2 has been injected is shown in Figure 21.

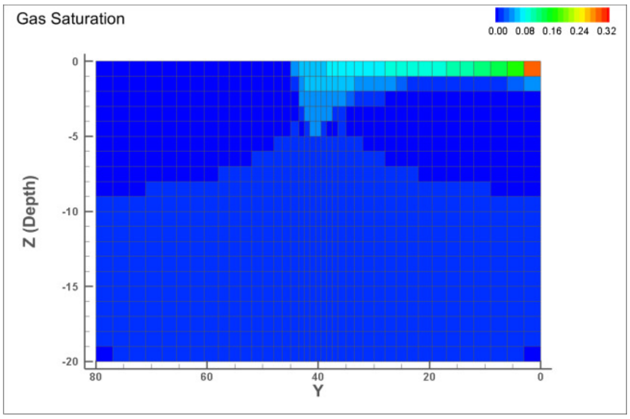

Figure 21. Gas saturation profile after CO_2 injection

The CO_2 injection well is located at the coordinates of (1,1) in the (*y*,*z*) plane. Gas gradually moves towards the production well and forms a gas cone. Due to the instabilities of the simulations in OLGA-Rocx when the gas reached the production well, further analysis could not be conducted. Installation of inflow control devices to prevent gas breakthrough could lead to proper gas storage and higher oil production.

5 Discussion

Based on the results of the simulations both the residual oil saturation and the curvature of the relative permeability curve are important parameters in CO_2 EOR as they affect the oil and water production from the well. Higher amount of oil can be recovered from the reservoir with lower water cut if the residual saturation of the oil can be reduced via CO_2 injection. Reduction of the residual oil saturation reduces the immobile oil content in the reservoir. At the same time oil will have a higher permeability compared to water even at lower oil saturations (Figure 7.). The effect of the residual saturation is extremely significant compared to the effect of the curvature shape of the relative permeability curve. If the residual oil saturation is high, oil permeability reduces rapidly as the oil saturation reduces, regardless of the curvature of the relative permeability curve. Hence residual oil saturation is more important factor than the shape of the permeability curve.

Both the location and the pressure of the CO_2 injection well have a significant impact on the oil production as well. A CO_2 injection well with higher injection pressure located at the top of the reservoir facilitates more oil production and less water production. When the injection well is located at the top of the reservoir, it can push oil in the top layer of the reservoir towards the production well. If the injection well is located at the middle of the reservoir, it will create an obstacle for the oil in the top of the reservoir to reach the production well. Due to the pressure effect of the injection well, water flowing from the bottom of the reservoir will be restricted.

Better results can be obtained from CO_2 EOR if CO_2 is injected as early as possible. At the early stages of the production, the oil saturation of the reservoir is higher and CO_2 injection can further enhance the permeability of the oil. If CO_2 is injected later, the effect of the permeability enhancement is not strong enough to compete with the permeability of water. The point at which the CO_2 should be injected is an economical factor. Generally it would be economical to produce oil with natural water drive as the water breakthrough occurs, and then CO_2 can be injected to enhance the oil recovery.

6 Conclusion

In this research work the effect of the CO_2 injection is represented through the changes in the relative permeability curves (i.e. residual oil saturation and the curvature of the permeability curve) and through the pressure effect of the CO_2 injection. All the simulations were conducted with a homogeneous, water-wet reservoir.

The most important parameter to be considered during CO_2 EOR is the residual oil saturation. The success of the CO_2 EOR system depends on its ability to reduce the residual oil saturation. Compared to the effect of the residual oil saturation, the effect of the curvature of the relative permeability curve is insignificant.

The optimum location of the CO_2 injection well and its injection pressure can be estimated via computational simulations. Based on the simple OLGA-Rocx simulations it is better to locate the injection well at the top of the production well. Higher gas injection pressure will produce oil rapidly but it can cause operational issues. Based on the simulations it can be seen that the gas can be injected at the reservoir pressure and as the pressure in the reservoir decreases, the pressure impact of the gas stream will be significant.

Since OLGA-Rocx is not fully compatible for CO_2 injection, these results have to be verified through more acceptable simulation tools such as Eclipse and with experimental results. Still this work produces a fundamental framework for the simulation of CO_2 injection via OLGA-Rocx platform.

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